DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

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IN THE MATTER OF NorthWestern Energy's	)	REGULATORY DIVISION
Application for Approval to Purchase and	)	
Operate PPL Montana's Hydroelectric Facilities,	)	DOCKET NO. D2013.12.85
for Approval of Inclusion of Generation Asset	)	
Cost of Service in Electricity Supply Rates, for	)	
Approval of Issuance of Securities to Complete	)	
the Purchase, and for Related Relief	)	

HUMAN RESOURCE COUNCIL, DISTRICT XI
NATURAL RESOURCES DEFENSE COUNCIL
RESPONSES TO THE DATA REQUESTS OF
THE MONTANA PUBLIC SERVICE COMMISSION

PSC-237

Regarding: Electronic Files and Supporting Information
Witness: Power

a. Please provide working electronic copies, with all links intact, of all spreadsheets and other analytic files used to support your testimony and associated charts.

b. If not already provided, please provide full citations to all the sources used for the charts appearing in your testimony (or refer to and provide a third-party source that contains full citations).

Response:

a. &. b See the files on the attached CD labeled "PSC-237 and PSC-246." Page numbers refer to Power Testimony

P. 10, figure. See file labeled:
Carbon cost comparisons_NWE_Synapse_western utilities_3_19_2014 PC.docx

P. 11, figure. See file labeled:

Carbon cost comparisons_NWE_Synapse_western utilities_3_19_2014 PC.docx

P. 18, figure: See file labeled:
Resource Comparison Charts and Table p. JMS-38 PC.xlsx, Tab: Hines Graph 3

P. 19, figure: See files labeled:
First link_MCC-154 Curve Calculator 6-7-13_power consulting.xlsx
Second link_Exhibit__JMS-1 and JMS-2 & p. JMS-20_power consulting.xlsx
Third link Resource Comparison Charts and Table p. JMS-38_power consulting.xlsx
Power Consulting Impact of Carbon Cost Assumptions Levelized Costs, which is a MS Word doc (for an explanation and instructions)

P. 20, figure: See file labeled:
Comparison of Hines and Power Consulting model results.xlsx, Tab: zero carbon

P. 29, first table: See file labeled: Testimony Tables PC.xlsx, Sheet 1

P. 29, second table: See file labeled: Testimony Tables PC.xlsx, Sheet 1

P. 30, table: See file labeled: Testimony Tables PC.xlsx, Sheet 1

P. 31, table: See file labeled: Testimony Tables PC.xlsx, Sheet 1

P. 32, table: See file labeled: Testimony Tables PC.xlsx, Sheet 1

P. 34, figure: See file labeled:
EIA Historical City Gate Price NG 2000-2014.xlsx, Chart 1.

P. 40, figure: See footnote on the figure. Copy of Figure 78, EIA Energy Outlook 2014

P. 41, figure: Copy of EIA Energy Outlook 2014, Figure 13

P. 42, figure: Copy of EIA Energy Outlook 2014, Figure 3.

PSC-238

Regarding: Principal-Agent Problem and Moral Hazard
Witness: Power

a. Please describe the principal-agent problem and moral hazard.

b. Can the principal-agent problem and moral hazard be used to describe relations between a regulated utility and its customers?

c. Can the principal-agent problem and moral hazard be used to describe relations between a regulatory commission and the public?

Response:

a. The generic principal-agent problem is the problem of how one party arranges to get a second party to effectively pursue the first party's objectives. This is typically arranged through a set of incentives that may be more or less effective. This could involve, for instance, an employer (principal) and an employee (agent) or it could be stockholders (principal) and the management (agent) of a company. Because it is costly for the principal to closely monitor and direct the agent, leading to asymmetries in information, the agent may be able to act against the principal's interest in favor of the agent's own interests if incentives do not link their two interests closely together. That is the moral hazard. This moral hazard can be phrased in terms of the agent engaging in behavior that is costly to the principal but beneficial to the agent. That is, the agent may tend to ignore costs (including those associated with risk) because the agent will not suffer the costly consequences. This could also be phrased in terms of a failure of the incentive structure to link the principal's and the agent's interests sufficiently together. Arranging such incentive systems, however, can be costly and cumbersome. Often the principal has to rely on cultural or moral standards such as honesty, loyalty, honor, etc. That is why the phrase "moral hazard" is used. The failure of the incentive system creates a situation that implicitly rewards a violation of moral or cultural standards.

b. Yes, to the extent that some costs associated with a utility's decisions can be shifted to its customers with little negative consequence to the utility.

c. Yes, to the extent that the regulatory commissioners can impose avoidable costs on customers with little negative consequence to the commissioners.

PSC-239

Regarding: Principal-Agent Problem and Moral Hazard
Witness: Power

For the following questions assume a principal-agent relation with NorthWestern as agent and its customer base as principal.

a. Do the principal and agent possess the same information, or is their information asymmetric?

b. Is the agent in a position to act to increase its own welfare at the expense of the principal?

c. Is the agent's action exposed to moral hazard? Please explain why or why not.

d. If your answer to part (c) is "yes," what actions may the Commission take to reduce the moral hazard?

Response:

a. It is asymmetric at the individual customer level.

b. That depends on the market setting. Businesses like NWE that engage in complex production processes or providing complex services often have more information that their customers. However, competition for customers can keep the businesses from exploiting their customers because of that information asymmetry. If there are no competitive suppliers and no close substitutes, NWE, for instance, could increase its own welfare at the expense of the customer. Regulation of monopolists by public commissions is intended to prevent that from happening.

c. A monopolistic utility not subject to regulation or significant competitive constraints could take actions that benefit it at the expense of its customers. Whether applying the concept of moral hazard to such actions adds any information about the situation is unclear.

d. Utility regulatory commissions were established to prevent utilities from using their market power to earn above-market returns on their investments. In the process of regulating the utilities through cost of service, however, a different set of incentive problems were created: Utilities were given the opportunity to recover their costs and earn a market return on their investments. That type of regulation could reduce or eliminate the utilities' interest in minimizing costs. In that setting, the combination of rates and risk faced by customers could be higher than necessary. For that reason, regulatory commissions have to scrutinize utility costs as well as impose reasonable limits on the return on investment.

PSC-240

Regarding: Principal-Agent Problem and Moral Hazard
Witness: Power

For the following questions assume a principal-agent relation with the Commission as agent and the Montana public as principal.

a. Do the principal and agent possess the same information, or is their information asymmetric?

b. Is the agent in a position to act to increase its own welfare at the expense of the principal?

c. Is the agent's action exposed to moral hazard? Please explain why or why not.

d. If your answer to part (c) is "yes," what actions may the Commission take to reduce the moral hazard?

Response:

a. The Commission, as an entity, is likely to have more information than the vast majority of customers.

b. That depends on how skilled the Commission is at explaining to customers why decisions that the Commission made that had negative consequences for customers were, nonetheless, correct and necessary. The Commission in Montana is elected and, in that sense, can be disciplined by the electorate. In other jurisdictions, Commissions are appointed by elected officials. Those elected officials may have much more information about the performance of the commissioners than customers do. Those elected officials could also discipline the commissioners. In addition, there are laws that impose major penalties for commissioners taking bribes or engaging in other self-interested behavior. Outside of simply not doing their job but collecting paychecks anyway, it is not clear exactly how Commissioners could materially increase their own welfare at the expense of the customers.

c. See the response to b. above.

d. See the response to b. above.

PSC-241

Regarding: Market structure
Witness: Power

a. Is the wholesale electricity market in the Northwest sufficiently competitive such that, absent any involvement by electric utilities, their regulators, and publicly-owned utilities (*e.g.*, ratepayer-backed construction of new resources or commitments to long-term PPAs with non-utility generators), unregulated entrepreneurs would construct the capital-intensive resources needed to satisfy demand in the timeframe needed to maintain current standards of system reliability? If so, what evidence supports that conclusion?

b. If the wholesale electricity market in the Northwest is not competitive to the degree described in part (a), is it reasonable to assume that the region could not sustain current standards of system reliability if all the publicly-owned and regulated investor-owned utilities undertook a strategy of relying solely on purchases from wholesale spot markets to provide all future resource needs?

c. If the wholesale electricity market in the Northwest is not competitive to the degree described in part (a), so that maintaining current standards of system reliability requires ratepayer-backed capital investments either directly by publicly-owned and regulated investor-owned utilities or through ratepayer-backed long-term PPA commitments, to the extent NWE were to undertake a strategy of relying solely on purchases from wholesale spot markets to provide all future resource needs, would it and its customers be free-riding on other utilities' ratepayer-backed capital investments?

d. Are you aware of other utilities that use the projected cost of wholesale spot market purchases as the only or primary measure of the cost-effectiveness of a potential capital investment in a new resource? If so, please identify those utilities and provide citations for the documentation of this practice.

Response:

a. The setting that has led electric utilities not to rely primarily on unregulated entrepreneurs to have sufficient non-contracted electric generating capacity on line to meet future customer loads may go beyond simply whether the electric market in the Pacific Northwest (or elsewhere in the nation) is "competitive." It can be "competitive" and also be "unreliable" and/or "volatile" just as many competitive commodity markets are.

   Most electric utilities, whether investor- , publicly- , or customer-owned have the obligation to provide adequate and reliable service to their customers at reasonable rates. Experiments, such as Montana's, to "trust the market" and let various electric suppliers compete to supply individual customers and let customer choose their own suppliers, in general, did not go very well. As a result, electric utilities have retained responsibility to acquire electric resources to serve their customers. Utilities are expected to provide reliable supply at as low and as stable a price as possible. Those can be conflicting objectives requiring tradeoffs.

   The complexity of those utility electric supply decisions and the public's interests in how well utilities made those decisions led to the adoption of publicly accessible integrated resource planning (IRP) by most electric utilities. IRP considered alternative supply portfolio on the basis of cost, risk, non-market public costs, etc. As the word "portfolio" suggests, it was expected that a variety of alternative sources of supply would be included to minimize risk and take advantage of existing technologies and economic circumstances.

   Electric generating facilities can take many years, up to a decade, to move from the planning and design stage through the permitting stage to construction and ultimate commercial electric generation. That and the capital intensive nature of electric generation make those investments risky if the future market for that output is uncertain. As a result, only a fraction of electric generation in the United States is provided by merchant generators without long-term contracts, although many merchant generators are tied by very long-run contracts to large industrial customers. In this setting, electric utilities have sought to assure reliable supply at relatively predictable and stable rates by planning to build their own generators or entering in to joint agreements with other utilities to build generating facilities or enter into long-term purchase power agreements that support a third party building generating facilities.

Finally, the integrated electric grid cannot operate unless there is assured supply to serve the firm loads that are placed on the grid from minute to minute. That is, if the collective demand placed on the system that cannot be quickly interrupted exceeds the collective resources available, the integrated system may fail leaving large areas without access to electricity. To avoid this, reliable electric supply has to expand with loads. This has been assured in the past by electric utilities physically assuring that generating capacity sufficient to meet much of their own load was brought on line in a timely fashion.

b. Yes. Note, however, that system reliability is only one of the concerns that electric utilities have to be concerned about. They also are concerned, for instance, about the stability of the costs of electric supply.

c. Yes. Free-riding has long been a concern in the management of the interconnected electric grid. Connected utilities could, for instance, not provide for reserves so that as loads changed, they simply drew on the grid to follow their share of the load. Utilities connected to the grid are required to meet a broad range of standards of behavior to fairly share the costs of reliability and minimize free-riding.

d. Dr. Power knows of no electric utility that engages in IRP that evaluates alternative sources of supply only by comparison to wholesale spot market purchases.

PSC-242

Regarding: Avoided cost benchmark
Witness: Power

a. At 21:18-22 you state that comparing the hydro purchase to continued over-reliance on the regional electric market is not a comparison with a reasonable alternative. Is this another way of saying that a projection of wholesale spot market prices is not a reasonable avoided cost benchmark against which to evaluate the cost of purchasing the hydros?

b. Is it important, economically, for the Commission to apply consistent measures of avoided costs when implementing the Public Utility Regulatory Policies Act of 1978 (PURPA), *i.e.*, setting rates for qualifying facilities, and evaluating resources NWE proposes for preapproval? Please explain why or why not.

c. In recent PURPA qualifying facility rate cases the Commission has measured NWE's avoided costs by blending near-term projections of wholesale market prices and the fixed and variable costs of owning and operating a combined cycle gas generating plant. Is the Commission's approach to measuring avoided costs in PURPA qualifying facility rate cases generally consistent with your analysis on pp. 15-23, as it regards the cost of alternatives to purchasing the hydros?

d. At 23:12-17 you indicate that a market-only-no-carbon-cost scenario involves significant risks, in part because it assumes regional electric and natural gas prices will stay relatively low. To the extent regional electric and natural gas prices impact the measure of costs that would be avoided by the hydro purchase, would it be reasonable for the Commission to consider alternatives to NWE's projections, for example natural gas price forecasts from the Energy Information Administration or the Northwest Power and Conservation Council? If not, please explain.

Response:

a. Yes. For non-firm "as available" generation, the spot-market electric price may be a reasonable "avoided cost." For the proposed hydro purchase the spot-market does not provide the basis for an avoided cost.

b. Adjusted for reliability, timing, duration, etc. of the generation, yes. PURPA sought to put utility-owned generation and generation from "qualifying facilities" on a level playing field. Having inconsistent measures of avoided cost does not establish such a level playing field.

c. Yes. Such an approach focuses on both the capital and operating costs associated with the most likely source of additional electric generation. Spot market prices, at best, reflect the operating costs of the marginal generating units that are brought on to meet load at particular times.

d. Yes, it would be reasonable. However, it is Dr. Power's understanding that NWE did exactly this in its analysis, namely, considered both of these alternative projections of natural gas prices. Evergreen Economics in its Final Assessment report to the MPSC (March 27, 2014) characterized the PowerSimm natural gas price projections in the following way:

   "For the first 10 years of the planning horizon (2014-2024), the PowerSimm mean forecast [of natural gas prices] is approximately equal to the 2013 Northwest Power and Conservation Council's (NPCC) medium case gas price scenario and the 2013 Energy Information Administration's (EIA) reference case gas price scenario. However, after 2024, the PowerSimm mean forecast falls below these comparison forecasts for each year after 2024." (p. 10)

   This suggests that the PowerSimm mean forecast underestimates natural gas price risk as indicated in both the NPCC and EIA forecasts.

   Evergreen Economics also describes NWE's market electricity price forecast in the following terms:

"For the first two years of the planning period, NWE's electricity price forecast is approximately equal to the 2013 NPCC electricity price projection (based on delayed implementation of a federal CO2 tax). NWE's price forecast then falls below the NPPC forecast from 2016 to 2021, at which point the carbon penalty enters into the NWE price forecast. The two forecasts are approximately equal for 2021. However, from 2021 to the end of the planning period, the NWE forecast is consistently below the NPPC forecast…" (p. 11)

Again, NWE's electric price forecast tended to understate the electric price risk compared to the NPPC forecast.

PSC-243

Regarding: Risks Associated With Aging Infrastructure
Witness: Power

You testify that "NWE appropriately included in its economic comparison of the hydro resource with alternative electric resource portfolios the other risks associated with each portfolio including uncertainty about future electric prices, natural gas prices, weather, customer loads, and coal prices." (3:5-8). Do you believe that NorthWestern adequately addressed, in its projections of capital improvement needs and costs for the hydro facilities, the potential range of risks associated with keeping a decades-old infrastructure operational, efficient, and safe? Please explain.

Response:

In Integrated Resource Planning, stochastic analysis is not extended to each and every variable that impacts the costs and risks associated with each resource and portfolio. Doing so is likely to be cost-prohibitive and make summarizing of the results so that decision-makers could understand them difficult if not impossible.

Thus, what the actual finished cost of an electric generating facility is actually likely to be years in the future or what the actual non-fuel operation and maintenance costs will be in the future, or potential costs associated with catastrophic failures, for instance, are rarely treated as stochastic variables. The focus is on costs and sources of regular risk that typically change the costs of almost any generating unit.

For instance, the probability that a CCCT will fail catastrophically or new regulation of emissions not even being discussed will be imposed at some future date along with many other possible future events are not typically treated as stochastic variables.

Whether the costs associated with maintaining the hydros in a condition sufficient to assure that they can continue to operate is so uncertain and large that it should be treated as a stochastic variable is an engineering question that neither I nor any other economist can answer. In this docket, engineers and hydroelectric operators are speaking to that question. However, economists can speak to distinctions among different types of costs and how they should be handled in an economic analysis.

PSC-244

Regarding: Capital Expenditure Uncertainty
Witness: Power

a. In his discussion about NorthWestern's stochastic analysis, Dr. John Wilson, a witness for the Montana Consumer Counsel, states that "… NWE makes substantial cost-increasing adjustments for uncertainties regarding purchased power alternatives, but fails to recognize and account for certain substantial future hydro plant cost uncertainties, such as capital expenditure requirements, which are potentially far greater." (Wilson 23:17-24:1) Do you agree that NorthWestern failed to recognize and account for future hydro plant cost uncertainties?

b. Do you agree with Dr. Wilson's statement that uncertainties related to capital expenditure requirements are potentially greater than uncertainties related to purchased power alternatives? Please explain.

Response:

a. Dr. Wilson is not an engineer who has studied the costs associated with older hydroelectric facilities. For that reason it is not clear to me how much weight his hypothesizing should be given. See the response to PSC-243.

b. That is an engineering question to which I cannot respond. See the response to PSC-243 and to a. above.

PSC-245

Regarding: Regulation of Carbon Dioxide
Witness: Power

a. When you use the term "developing regulation of carbon emissions" (2:5-6), what regulation precisely are you referring to?

b. Are you aware of other regulations now "developing" that would affect carbon pricing for electric generating units in Montana other than the new-source and existing-source performance standards for greenhouse gas emissions being developed by the EPA under Sections 111(b) and 111(d) of the Clean Air Act? If so, please identify other regulations and describe their impact on carbon price.

c. When you state that NorthWestern has "appropriately accounted" for carbon risk (2:5), do you mean that the carbon prices NorthWestern used in its deterministic and stochastic modeling are an appropriate proxy and expected result for the regulations mentioned in subpart (b) of this question? If so, how can you be sure that as yet unwritten regulations such as the 111(d) regulation of greenhouse gases will result in particular prices as presented by NorthWestern?

Response:

a. All of the steps being taken at the federal, state, and local level to discourage the emission of carbon from electric generators. At the current time in the United States, the federal regulation of electric generator carbon emissions has not taken the form of a carbon tax or a market-derived carbon price. Instead it is taking the form of direct limits on the carbon emissions from different electric generators. At the state level, some west coast states are adopting their own carbon pricing regimes. Some west coast states are also acting to block the importation of electricity from high-carbon sources elsewhere in the West. The states of Washington and Oregon have taken steps to schedule the retirement of the largest coal-fired generators in their states (Centralia in Washington and Boardman in Oregon) and Washington is investigating the wisdom of Puget Sound Energy continuing to invest in the Colstrip 1 and 2 plants. In Montana, PPLM has announced the planned mothballing of the Corrette coal-fired plant in Billings. All of these are part of the developing regulation of carbon emissions. All of these decisions are likely to impact the regional cost of electricity going forward.

b. Federal regulators have proposed limits on the emissions from new electric generators. EPA is now working on emission standards for greenhouse gas emissions from existing electric generators. EPA has indicated that it plans to provide states with compliance flexibility. The acceptable approaches may include regional marketable carbon emission mechanisms. In 2007 the governors of Arizona, California, New Mexico, and Oregon announced the Western Climate Initiative that seeks to develop a multi-sector, market-based approach to greenhouse gas regulation. Washington and Oregon have adopted measures to eliminate coal-fired generation their largest fossil-fuel electric generators.

   This ongoing development of emissions, including carbon, regulation on coal-fired generators will increase the cost associated with electric generation from high carbon sources and put upward pressure on market electric prices.

c. Dr. Power's testimony was that the *approach* taken by NorthWestern to model the costs associated with the developing regulation of carbon emissions from electric generators was appropriate. Dr. Power was not saying that the cost of carbon resulting from regulations under 111(b) and 111(d) was precisely captured by the carbon prices utilized by NorthWestern.

The carbon prices used in modeling by NorthWestern and other utilities and electric utility analysts such as the Energy Information Administration are "stand- ins" for the increased costs that will be imposed on higher carbon intensive generation. Exactly what form those higher costs will take (e.g. carbon tax, market price from cap and trade, increasingly costly required emission controls, embargos on the export of high carbon electricity sources, or other mechanisms), the cost associated with fossil fuel generation will rise.

If we knew exactly what the future costs associated with electric generation in the future were, we would not have to make *projections*. We would just enter that certain knowledge of the future into our analysis. We do not know exactly what natural gas or coal will cost to fuel electric generators in the future. We do not know what spot market prices of electricity will be in the future. We do not know exactly what it will cost to plan, permit, and build electric generators in the future. We do not know what technological developments will do to the cost of alternative generating technologies. Etc.

But if we are going to do any analysis of the economics of alternative sources of future electric supply, we have to project future uncertain costs. That includes the cost associated with the developing regulation of carbon emissions. Uncertainty about the future is frustrating. But it is a fact of economic life.

PSC-246

Regarding: Source Documents on Carbon Pricing
Witness: Power

a. Please provide the "2013 Carbon Dioxide Price Forecast" published by Synapse Energy Economics, Inc., referred to on 6:11-12.

b. Please provide a full copy of the "Carbon Disclosure Project-North America, December 2013" paper or document used to source the table appearing on page 7 of your testimony.

Response:

a. The "2013 Carbon Dioxide Price Forecast" published by Synapse Energy Economics, Inc. can be downloaded from https://www.cdp.net/CDPResults/companies-carbon-pricing-2013.pdf . This document is also provided on the attached CD labeled PSC-237 and PSC-246, file name: SynapseReport 2013.

b. "Carbon Disclosure Project-North America, December 2013" can be downloaded from http://www.synapse-energy.com/Downloads/SynapseReport.2013-11.0.2013-Carbon-Forecast.13-098.pdf . This document is also provided on the attached CD labeled PSC-237 and PSC-246, file name: "companies-carbon-pricing-2013."

PSC-247

Regarding: Carbon Price Projection
Witness: Power

a. On p. 7 you provide a table of private companies that are projecting carbon prices for internal use. It appears that Exxon Mobil has projected a price of $60 and Royal Dutch Shell has projected a price of $40. Do you believe it is likely that either of these companies would invest significant capital based upon these figures, without offsetting hedges in place to protect the company in the event that high carbon taxes did not occur?

b. The projected prices in the table range from $6 (Microsoft) to $60 (Exxon Mobil). ConocoPhillips apparently uses estimates ranging from $8 to $46. In your opinion, what is the cause of this variability in prices? Is it related to a paucity of historical carbon price events?

c. The four highest prices shown in the table are estimates from companies with significant investment in petroleum and its derivatives (BP, Conoco, Exxon, and Shell). Do you believe that these high price projections will inspire these companies to exit the fossil fuels market in anticipation of cratering profits due to carbon taxes?

Response:

a. These companies *are* investing significant capital knowing that in the future high carbon energy resources *will* be more costly to use because of the regulation of carbon emissions. These companies know that the regulation will get tighter over time and the cost imposed on the combustion of carbon-intensive fuels will rise. They are planning strategies so that they can remain profitable during that transition to increasingly strict and costly regulation of carbon emissions. That is the point of facing the expected costs and planning to cope with those costs.

b. The broad range of values likely reflects differing judgments about the timing and size of the costs associated with regulation of carbon emissions. The absence of a historical pattern that can be used to inform the projections certainly contributes to the wide range of projections.

c. No. Exiting an industry where high future costs are projected is not the only or likely response of an entrepreneurial firm. The point of the projections is to allow the firm to adapt to those higher costs or even take advantage of the expected higher costs to earn higher profits. Businesses that surrender and go out of business every time there is a negative impact on the horizon for their firm do not stay in business in a market economy very long. American businesses have weathered a broad range of increasingly strict environmental regulations without simply shutting down. They have also weathered fluctuating prices for their basic inputs and stiff competition from new technologies and processes. That is the character of a market economy.

Successful businesses look at the future in a hardnosed way and plan to successfully navigate that future with all of its obstacles and opportunities. Ignoring potential future costs or not acting to deal with them until they are a reality is unlikely to be either a prudent or successful business strategy.

PSC-248

Regarding: Realization of Carbon Cost in Purchase & Market Prices
Witness: Power

a. With respect to the charts showing other utilities' expectations of carbon price represented on pages 10 and 11 of your testimony, are you aware of whether any of these companies have been in an analogous position to NorthWestern (i.e., purchasing an existing asset whose production is expected to have a greater, or lesser, value in the future because of a future carbon price) and did what NorthWestern is proposing (i.e., capitalizing the expected future value of avoided carbon costs)? If so, please list those companies and describe the analogous situation.

b. For any companies listed in response to part (a), please identify those that captured that future value in present markets, from present consumers, even though the future value of avoided carbon costs had not yet been priced into the market.

c. Do the forward market curves used by NorthWestern include a carbon price that is internalized within the price offered to and taken by purchasers?

Response:

a. Every electric generator that has made a decision about what type of electric generation to add to its supply portfolio has done exactly what NorthWestern has done in its analysis of alternatives and its decision-making.

   In making the decision about whether to build coal, natural gas, nuclear, wind electric, or other renewable generator, utilities have to project the expected costs associated with each. The fuel costs are uncertain. The costs associated with potential environmental regulation are uncertain. Delays in permitting different types of plants are uncertain. The demand for electricity in the future is uncertain. Etc. All of these uncertain costs have to be evaluated and a choice has to be made. Implicit in the choice that is made is the "capitalization" of all of those expected costs. That is unavoidable if one takes seriously the potential costs associated with all of the alternatives.

   The shift from coal-fired electric generators to natural-gas fired generators is a good example of the judgments that electric utilities had to make. Coal-fired generators typically have lower fuel costs than natural gas fueled generators. Regulatory uncertainty and costs associated with coal plants, however, are higher and the time to plan, permit, and build tends to be much longer. The capital tied up in a coal-fired plant is higher than for a gas-fueled plant. Etc. It would be imprudent to ignore these differences in the cost structure of the alternatives. As a result, those cost differences tend to dictate the choice of one type of generator over the other. That is, differences in projected future costs and risk drive the decision and get embedded in the cost of the facility chosen that customers then support with their rates if regulatory commissions approve that new source of supply.

b. When natural gas fueled electric generators are presented to regulators for ratebase treatment and fuel cost recovery, utilities are asking for their projections of the future regulatory costs of coal compared to natural gas and future projections of the comparative coal and natural gas costs to be accepted and passed on to customers. It is the higher projected costs associated with coal-fired generation, including the high projected costs associated with regulation of the emissions of coal combustion that justifies the risks associated with natural gas prices that is taken on when a natural gas fueled generator is chosen.

c. Dr. Power is not aware of any analysis that has been done to determine whether current forward market curves reflect the internalization of carbon costs.

PSC-249

Regarding: Representation of Other Utilities' Carbon Forecasts
Witness: Power

a. You write "[o]f the 13 Western electric utilities used by NorthWestern for comparison purposes, only Tacoma Power *projected* lower mean carbon prices." (9:17-18) [emphasis added]. Elsewhere, you observe that NorthWestern eliminated certain forecasts that these other utilities used from the mean value that NorthWestern presents, even when those forecasts were sometimes those utilities' "base" cases (12:27-13:4). Did these other utilities really "*project*" these mean carbon prices or did NorthWestern select certain parts of other utilities' data for its own projection?

b. Of the Western utilities carbon prices you re-work and present on p. 10, how many zero-cost cases did NorthWestern's analysis ignore? How many of these were "base" or "reference" cases? Please identify those utilities.

c. Of the utilities Synapse used in its analysis, which you re-present on p. 11, how many have zero-cost cases as their "base or "reference" case? Please identify those utilities.

d. How many of the utilities represented in Synapse's work used multiple scenarios? Please identify those utilities, as well as how many scenarios they used.

Response:

a. NorthWestern, like many other electric utilities in the West and across the nation, engages in integrated resource planning that requires the specification of an expected range of various future variables that are assumed to be important in the choice of additional electric resources. NorthWestern, like many other utilities included its best estimate of future carbon costs and specified a range of uncertainty around that carbon cost. Whether these are called “projections” or “assumptions” or “estimates” is not central.

   Northwestern sought to compare what was its estimated mean carbon cost projection to the mean or base or middle estimates that other utilities used. It did, however, reject estimated mean carbon costs that were zero. NorthWestern stated that it did that and why. See Power direct testimony pp. 9-15.

b. Dr. Power did not go back to the individual utility IRPs to see what each utility estimated its low, medium, and high carbon cost estimates to be. Dr. Power noted one utility, Avista, that had a base or reference case that had carbon costs at zero. It was the comparison of the NWE figure and the Synapse figure that identified that utility. NWE’s figure does not report base or reference cases but an average across all of each utilities range of carbon cost values.,

c. The Synapse graph on page 11 of Dr. Power’s testimony shows only one utility, Avista, that assumed zero carbon costs for its base case.

d. Dr. Power assumes that most of the utilities represented in Synapse’s work used multiple scenarios. Indicating a range of possible carbon costs, as NWE did in its stochastic analysis is the standard practice. Dr. Power has not gone through all of the IRP’s on which Synapse based its graph of utility carbon cost assumptions. Typically at least three alternatives are considered, a reference (or “base”, “most-likely,” or “medium”) assumption and then a low and high assumption. Some, like Avista, use more categories, e.g. Avista’s low, mid, high, and very high carbon costs.

PSC-250

Regarding: Carbon Price Projection
Witness: Power

a. Many of the price curves shown on pp. 10-11 were projected by regulated investor owned or public utilities. In your opinion, are any of these utilities at risk of serious financial loss if their projected price levels and escalation rates are not realized?

b. In your opinion, would a regulated utility benefit from projected carbon prices that exceed realized carbon prices to the extent that the inflated carbon price projections justify investment in expensive resources that provide increased profit opportunities?

c. In your opinion, are the customers of a regulated utility better off, or worse off, if the utility makes unnecessary investments due to inflated carbon price projections?

d. In your opinion, are NorthWestern's carbon price projections exposed to moral hazard? If so, should the Commission discount NorthWestern's carbon price projections?

Response:

a. It is likely that all of the regulated utilities whose carbon cost assumptions are shown on the figures on pages 10 and 11 of Dr. Power's testimony are engaged in Integrated Resource Planning processes. Those planning processes are intended to document the analysis that the utility went through in making electric supply decisions. The carbon cost assumptions, like the assumptions about natural gas, coal, and electricity prices as well as load growth, etc., are likely to impact which additional electric supply resources has the lowest expected costs and risks. To the extent that this leads to a choice of a particular new source of supply, the utilities could be at risk of recovering the costs of the chosen resource when the utility brings that resource to its regulatory commission for rate treatment. In that sense *all* of the regulated investor owned utilities are "at risk of serious financial loss if their projected price levels and escalation rates" are not realized. This applies not just to carbon prices but all of the other assumptions made in their planning process.

b. If the regulatory commission set the cost of capital correctly, it will reflect the rate of return on investment that is available elsewhere in the economy for investments of similar risk. In that setting there is no excess return to be earned by the regulated utility. The utility's investors will be neutral about investing in that particular utility project or pursuing the same rate of return elsewhere. In that sense there are no "increased profit opportunities" associated in investing their dollars in an overpriced generating facility. Regulatory responses and customer responses to such bad management might actually damage the earnings potential of the utility.

c. If a utility makes an unnecessary investment that is accepted for rate making treatment, customers will be worse off. If the utility, however, makes unnecessary and unsupported investments for any reason, those investments should be disallowed. On the other hand, if a utility invests, say, in a gas-fired generator rather than a coal-fired generator based on the best available information on what regulatory costs associated with coal-fired generators were expected to be and based on projections on how low natural gas costs were expected to be, and those cost projections were not borne out, that is likely to be treated as a prudent decision based on what was known at the time. Utilities, like all businesses, have to evaluate future conditions and make the best judgment they can.

d. If this Commission sets the cost of capital correctly, NWE investors will earn no more and no less than they could earn elsewhere if they put their money in a new NWE electric supply resource as opposed to some other investment in the national or world economy subject to similar risk. There is no moral hazard involved any more than there is in every single projection NWE has to make about future economic conditions as it manages its electric and natural gas utility. The Commission's job is to examine the reasonableness of NWE's assumptions. Discounting those projections on the basis of hypothesized "moral hazard" does not seem appropriate.

PSC-251

Regarding: Carbon Price Risk
Witness: Power

a. Have you estimated how much of NorthWestern's proposed $900 million purchase price for the hydro resources is value imputed from its expected cost of future carbon emissions? If so, please provide that amount along with any underlying work papers.

b. If your answer to part (a) is "no," do you agree with Dr. Wilson that about $247 million of the proposed purchase price of $900 million for the hydro resources is value imputed from expected increases in energy costs due to future carbon costs, based upon the Stimatz DCF model and carbon price curves?

c. If the Commission approves purchasing the hydro resources for $900 million, but the expected carbon costs do not occur and market costs are lower than NorthWestern projected, do you believe customers will be negatively affected by the cost of the hydropower relative to market resources?

d. In your opinion, would a combined purchase of the hydro and coal-fired facilities provide a hedge against the uncertainty in carbon prices, if the same carbon price forecast was reflected in the initial purchase price of the coal assets?

Response:

a. No. NWE makes clear that its proffered purchase price, both the original one and the final $900 million, were based on a wide variety of different considerations, not just on one particular measure. See the testimony of Robert Rowe, Brian Bird, John Hines, and Joseph Stimatz. Given the multiple types of analysis carried out and the many judgments made in combining all of that information into an offer to PPLM, it is not possible to say exactly what role the expected costs associated with the regulation of carbon emissions played. That is also true of all of the other data inputs, such as natural gas prices, market electric prices, coal prices, capital costs associated with alternative technologies, potential changes in emission regulations, etc.

b. Dr. Wilson did not estimate "what part of the proposed purchase price of $900 million for the hydro resources was value imputed from expected increases in energy costs due to future carbon costs." He took the Stimatz DCF model and reduced the projected regulatory costs associated with carbon emissions to zero and determined what the net present value of the cash flows associated with the hydros would be. (This may or may not have been done accurately. There is some question as to how the Kerr transfer price and the impact of depreciation on income taxes was handled.) The most this calculation can show us is how an assumption that there will be no future costs associated with the regulation of carbon affects the DCF analysis, one of the many tools NWE used to evaluate the purchase of the hydros. It does not tell us how the proffered purchase price would have been changed.

c. The world is an uncertain place in which to engage in any activity, including business activity. If you make a decision based on one set of assumptions and those assumptions do not become a reality, you will be either better or worse off than you expected to be. That is what uncertainty means. It does not mean that you necessarily made a mistake or were foolish. Not making a decision could also leave you either better or worse off. So, yes, there are clearly future developments that in retrospect would not make the purchase of the hydros looks as favorable as had been expected. There are also future development that could have the opposite impact, making the purchase look brilliant. Utilities, like all businesses and all citizens, have to make decisions in the face of uncertainty. One has to face that uncertainty and seek to manage it as best one can. NWE sees the purchase of the hydros as a major step in doing exactly that, reducing future electric supply risk.

d. Purchasing all of PPLM's generating resources would give NWE far more generation than they needs to serve its customers. NWE would become a merchant generator, something that is not part of their business plan and something this Commission has not encouraged it to do. Owning excess resources and selling it into the uncertain electric market would put either NWE's stockholders and/or customers at risk of not covering costs. In addition, at this time, it would not appear to be prudent to adding considerably more coal-fired generation to NWE's portfolio given the uncertainties about future regulation of coal-fired emissions (other than carbon costs). PPLM already is planning to mothball the Corrette facility and there is pressure on some of the owners of Colstrip 1 and 2 to consider retiring those plants. There is also impending regulation of the coal-ash combustion waste and its impact on water and health. Buying all of PPLM's generating facilities would be speculative and dangerous to both customers and stockholders.

PSC-252

Regarding: Carbon Taxes
Witness: Power

a. To the extent you know, what percentage of (1) Montanans and (2) Americans are skeptical of the idea that the nation needs to curtail carbon emissions?

b. To the extent you know, how would a typical lower-income Montana resident weigh the net value of near-term increases in their energy bills in order to offset potential increased market costs from carbon taxes in 2021 and beyond?

c. To the extent you know, how would a typical lower-income Montana resident weigh the net value of paying higher energy costs, now and into the future, in order to achieve economic and environmental benefits of avoided carbon emissions?

d. In your opinion, do carbon taxes impose immediate and measurable costs on ratepayers based primarily on projected future benefits that are difficult to quantify?

e. In your opinion, will many people oppose carbon taxes once they realize their energy bills will be impacted? Please describe the basis for your certainty in carbon regulation. (p. 8:7).

Response:

a. Dr. Power has no expertise in designing or interpreting public opinion polls.

b. From a narrow financial point of view, low income households tend to have quite high discount rates, favoring spendable income now and in the near term over having access to that income at some distant future date. From a broader public or social point of view, Dr. Power is not aware of any data indicating that low income households oppose long term public investments in schools, libraries, parks, and other infrastructure. Nor is he aware of data indicating that low income households tend to oppose environmental regulation that has some upfront costs but makes water and air safer to all citizens.

c. Low income households suffer more from degraded environmental conditions than middle and high income households, both on the job and in their neighborhoods. That is why environmental equity has become an important consideration in evaluating environmental impacts. Just as low income households tend to live in more polluted neighborhoods now, it is highly likely that they will also suffer disproportionately from climate change. Using the short run costs of environmental improvement on low income households as a justification for not making those improvements would be perverse given who it is that is likely to benefit the most from those improvements. The focus should, instead, be on a more equitable distribution of those costs.

d. No. Projections of higher or lower natural gas prices, of higher or lower electric market prices, of higher or lower coal prices, of technological changes that raise or lower the costs of particular generating technologies, etc. etc. all could be said to impose "taxes" on ratepayers because they lead to the adoption of one type of generator as opposed to another. For decades we built coal-fired and nuclear generators despite their very high capital costs and long planning-permitting-construction periods. The justification was that the fuel costs would be much lower than the natural gas fuel costs associated with much cheaper natural gas fueled generating plants. Now the judgment about the future has us favoring natural gas plants over coal despite the higher fuel cost risk associated with relying on natural gas. Projections of future costs and prices always could be said to involve imposing the costs of an uncertain future on current rate payers. This is unremarkable and unobjectionable. As far as imposing immediate costs to realize future benefits, there are accounting and ratemaking procedures available to spread the upfront costs more evenly across current and future consumption.

e. Carbon regulation is already underway. First of all, the question seems to assume that a carbon tax is the only method of reducing carbon emissions. As discussed in answer to PSC-245, a carbon tax is but one method of carbon regulation. What is uncertain is whether, contrary to most environmental regulation in the past, one expects that carbon regulation to be dismantled in the future rather than proceeded to grow more and more strict "Carbon taxes" may or may not be adopted. Regional cap and trade may be adopted because the businesses being regulated see it as a way of reducing the cost of meeting any given carbon emission objective. EPA's current "old fashion" regulation of emissions from each particular source is likely to be seen by those being regulated and the regulators as clumsy and inefficient. Even if a more comprehensive approach to regulation of carbon emissions is not implemented, carbon regulation is going to lead to the retirement of carbon intensive electric generators. That is already planned for the largest coal-fired electric generators in Washington and Oregon (Centralia and Boardman) due to state-level carbon regulation. California and Washington are also indicating that they will seek to block the importation of coal-fired electric generation from other western states. As discussed in Dr. Power's testimony, investors and utilities have largely concluded that investments in new coal-fired electric generators are not prudent. Carbon regulation is already changing the mix of electric generation in the region and that is likely to continue. It will also have impacts on electric supply and prices. Predicting the public's response to all of this lies outside of Dr. Power's expertise.

PSC-253

Regarding: Modeling Carbon Taxes
Witness: Power

At 26:13-14 you state: "Where there is not information on past variation, an assumed frequency distribution has to be developed."

a. Is the triangular distribution Ascend Analytics (Ascend) used to model carbon prices in PowerSimm an assumed distribution that fits this description?

b. It appears that the distribution is symmetric in each period, with the mode pegged to NorthWestern's carbon price forecast, a lower bound of zero, and an upper bound equaling twice the mode. Given this, what information does the distribution provide that is not contained in the carbon price forecast?

c. In your opinion, is a triangular distribution more plausible or useful in this case than a uniform distribution or a discrete distribution with positive point probabilities?

d. In your opinion, given that an extensive body of carbon price data does not exist, does stochastic modeling of carbon prices provide significant additional value compared to deterministic modeling of a range of potential carbon prices?

e. The PSC's consultant, Evergreen Economics, as well as multiple commenters to the 2013 Resource Procurement Plan (the Montana Consumer Counsel, the Montana Environmental Information Center) criticize NorthWestern for not including a full range of scenarios (e.g., low, medium, high) of values for carbon price. Do you agree with this criticism? Please explain.

Response:

a. Yes.

b. The triangular distribution used does contain information about the assumed frequency distribution of the possible values. For instance, if one wanted to estimate 90/10 percent ranges of values, one could do that. The triangular distribution provides a complete distribution of values with associated probabilities for all of the values between the low and high value. If one is only interested in the mean value and the expected value of all values above the mean (or below the mean), then all that information is already available in the low, high, and mean value of this particular symmetrical triangular distribution.

c. Yes. If one believes that as one approaches the low or high value the probability of either of those extremes is much lower that the "most likely" or "expected value," the triangular distribution is more appropriate.

d. This question runs two questions together. One is whether stochastic modeling is valuable in utility integrated resource planning. The other is whether the use of a triangular or other constructed distribution function should be used for carbon costs in the stochastic modeling.

   In the past, the Montana Power Company and NorthWestern have both agreed that stochastic modeling should be used to evaluate the risks associated with utility resource supply decisions. This Commission has long supported that sort of stochastic modeling. Only using deterministic modeling makes analysis of the risk and uncertainty associated with alternative electric supply portfolios difficult.

   Deterministic modeling such as DCF analysis accompanied by sensitivity analysis can be biased by the choice of values and difficult to interpret. On the other hand, as Evergreen Economics has pointed out, one does not have to choose between stochastic modeling and sensitivity analysis. One can check the stochastic outcomes against changes in input assumptions to identify the key variables that are likely to heavily influence the outcomes of the stochastic analysis.

Finally, triangular distributions are widely used in practical situations where:

i. There is little data on which to base a frequency distribution of outcomes.

ii. There is reasonable confidence that a practical minimum and maximum can be specified and that there is information supporting a central tendency value.

iii. Very large and very small extreme values with very low probabilities are considered unimportant and/or distracting.

It is unlikely that the use of a triangular distribution for the carbon costs caused problems within the stochastic analysis.

e. See d. above. Dr. Power did not interpret Evergreen Economics' statement about sensitivity analysis of the stochastic outcomes as saying that the stochastic analysis should be abandoned for deterministic DCF analysis that uses "low," "medium," and "high" values for all of the stochastic variables. Rather, Evergreen appeared to be saying that within the context of the stochastic analysis, one could check to see how changes in key variables and their assumed distributions impacted the outcomes of the stochastic analysis. If the outcomes are quite sensitive to the assumptions about one or two variables, that would be useful information that might indicate that more thought should go into verifying one's confidence in those values and their distribution. Dr. Power has not reviewed all of the comments on NorthWestern's 2013 Resource Procurement Plan and so can offer no opinion on statements made in those comments.

PSC-254

Regarding: Modeling of Risk in PowerSimm

Witness: Power

At 27:8-30:20 you discuss how Ascend modeled risk in its PowerSimm model.

a. Was it proper for NorthWestern and Ascend to design the PowerSimm model to ignore the risks associated with the possibility of large and unanticipated capital expenditures that could be necessary to keep the dams operating?

b. Do you believe that river flows are effectively modeled using a 30 year history? Is there reason to assume that flows may depart from a 30 year model? Please explain what factors could influence river flows.

c. How did Ascend measure downside risk, i.e., the risk that locking in cost-of-service based rates for a very large asset like the Hydros might cause the consuming public's price of electricity to exceed the market price?

d. You list the risks modeled by Ascend at 30:6-8. Are there risks not included in this list and not modeled by Ascend? What are they?

Response:

a. Whether NorthWestern and Ascend should have incorporated into its stochastic model the risks associated with the potential for large and unanticipated capital expenditures that might be necessary to keep the dams operating, depends on the existence of quantitative information that allows the size and the likelihood of such a series of occurrences. Stochastic analysis does not incorporate a quantification of any and all risks that might exist. The answer to this question had to be based on engineering economic analysis.

   Dr. Power's understanding is that NorthWestern studied the maintenance, repair, and upgrade strategy that PPLM had been following and based on that analysis NorthWestern projected what additional investments would be needed over the next three decades to maintain the productivity of the hydros. The appropriateness of that analysis by NorthWestern's hydroelectric managers and the engineering firms NorthWestern employed is an engineering question to which Dr. Power cannot speak.

   It is Dr. Power's understanding that catastrophic failure of generating units is not usually modeled in stochastic IRP. See also the response to PSC-243.

b. It is Dr. Power's understanding that NorthWestern reviewed both 5-year and 20-year historical generation as well as the historical generation provided by PPLM. (Stimatz Direct Testimony, pp. 6-8).

   Dr. Power is not an expert in hydrology or the effect of climate change on precipitations patterns and has not studied river flows in Montana rivers. He cannot offer an expert opinion on the question asked.

c. See the response to PSC-241 and PSC-251.

   This question assumes that the primary obligation of a regulated utility and of the regulation of that utility is to assure that the cost of the electric supply portfolio at all times is at or below the market price of electricity. That is not Dr. Power's understanding. Regulated utilities are expected to provide adequate and secure electric supply at a reasonable price. Fixed investments or long-run fixed contracts that seek to keep long run electric supply prices below what they otherwise would be fits into that charge even if it means that at time electric supply costs are above short-run market prices.

   NWE and Ascend *did* stochastically model a portfolio that added no new supply resources except market purchases comparing it to portfolios containing fixed investments in a variety of supply resources including the hydro. That, however, was a long-run analysis looking out over 30 years and calculated the expected values over the entire period.

It is important to note that the reference point in that modeling cannot be some already *known* set of future electric market prices. We do not know what future electric prices will be. Future electric prices, natural gas prices, the costs associated with future environmental regulation, coal prices, the cost and efficiency of future electric generating technologies, etc. are all unknown. This question asks how the possibility that the rates that result from the purchase of the hydros might be above or below the unknown future, but variable, market prices.

In order to reduce customer exposure to market risk, NWE considered two and later three more alternative additions to its supply portfolio that involved fixed investments. Such capital expenditures, by their very nature, represent fixed costs that are incurred to avoid other market or regulatory risks. If those projected future risks do not result in the projected costs being realized, it is always possible with the wisdom of hindsight to assert that a mistake or error was made. Business firms and public agencies, however, regularly *do* make investments in fixed capital to provide for the future rather than exclusively rely on markets to purchase supplies and services as needed on a day-to-day or year-to-year basis. In general economists have not condemned such fixed investments as mistakes because of the possibility of "downside risks." The national fleet of electric generator and the related transmission grid are the result of such fixed capital investments as is almost all existing economic infrastructure.

d. Yes. There is probably no limit, except for the imagination of the analyst, to the risks that could be listed that would make the hydros more or less productive or more or less costly to ratepayers. As part a. of this data request points out, the possibility that the hydros will require much higher levels of O&M and CapEx to maintain their productivity is not treated stochastically. It does not appear that potential risks in the level of future O&M costs are considered for any of the other portfolios either. Similarly, catastrophic failure that resulted in one or more hydro units having to be abandoned was not included as stochastic variables, nor was such catastrophic failure considered for any of the other alternatives either. Additional environmental regulation of the hydros or of the emissions (other than carbon) especially associated with gas-fired combustion turbines were not stochastic variables. Also see the response to PSC-243.

PSC-255

Regarding: Value of the PowerSimm Model
Witness: Power

Should the Commission discount the value of the PowerSimm model for the purpose of evaluating whether preapproval of the Hydros acquisition is in the public interest, given that the Commission and intervening parties did not have access to the model for the purpose of checking the sensitivity of outcomes to alternative parameter and probability distribution specifications?

Response:

Access to consulting firms' proprietary and very complex models has long been a frustration for parties participating in utility regulatory proceedings. For NWE's first several electric resource acquisition plans, NWE used a different proprietary model, the GenTrader model, to carry out its cost and risk analysis of alternative portfolios to meet its customers' electric demands. Although GenTrader's owners were always willing to demonstrate the model, they were not willing to distribute it to all interested parties. Even if they had, it is not clear that many or any parties would have had the skill and knowledge to run the model. This also has been the source of problems with cost of service analysis with each party providing their own expert who used a different proprietary cost of service model. NorthWestern, to its credit, has attempted to work with a consultant to develop a cost of service model that was not proprietary and that each party could manipulate if it wished. That, in Dr. Power's experience, is unusual.

Part of the unease with the PowerSimm Model is that it is new, the consulting company and its personnel are new, and the parties to this case have had only a few months of experience to understand how it operates and figure out how phrase strategic questions to NWE and its consultants so that parties can understand the inner workings of the model and test its sensitivity to key assumptions.

The Montana Commission had previously criticized the GenTrader model for not really having been designed to analyze the costs and risks of alternative portfolios. It appears that the PowerSimm Model will be a more useful and functional model in integrated resource planning. It seems unlikely that the Commission would want to reject all testimony that was based on proprietary models. The better solution is to arrange for Commission staff and parties to a case to get reasonable access to the consultants and for sensitivity runs to check the reliability and consistency of results.

PSC-256

Regarding: Combined Cycle Combustion Turbine (CCCT) Comparison
Witness: Power

a. With respect to the chart appearing on page 19, did you make the same assumptions about CCCT capital costs and gas prices as NorthWestern did?

b. What would this analysis look like if the 2011 RPP inputs for CCCT capital costs were relied upon? Would CCCT look like a relatively better value?

c. Why is it appropriate to assume only scenarios that have carbon price escalating at 3 percent or greater (you depict 3, 5, 7 and 10% scenarios), despite the fact that other costs are escalated on an assumption of 2.5% throughout the Hydros' life?

d. Montana-Dakota Utilities, in its integrated resource plan, assumes co-ownership of a CCCT to achieve greater economies of scale. NorthWestern does not. Do you believe that NorthWestern's expectation, that it alone would bear the burden of building a 238 MW CCCT in 2018 (one of the first modeled portfolios), is a proper one?

Response:

a. Yes.

b. This question cannot be answered without modifying the input assumptions and redoing all of the modeling that NWE has done. Dr. Power has not done that analysis and therefore cannot answer this question precisely.

However, the assumed capital costs used in both the 2011 and 2013 RPPs were quite similar.

If the capital cost of the CCCT per kw was expressed in the same terms in the 2011 and 2013 RPPs, the 2011 cost expressed in 2013 dollars would have been slightly cheaper (10 percent). The 2013 value, however, was within the 2011 range of CCCT capital costs. Of course there is no reason to expect the costs of electric generating equipment to be constant from year to year. As MDU commented in its 2013 IRP: "Historically the costs of materials associated with the construction of generation have increased at a rate higher than general inflation both in the United States and the rest of the world." (p. 21, Volume IV, Attachment C) One has to look at the costs at the time the planning is being carried out, not in some past year. These costs are not usually the subject of controversy since many utilities are considering the same types of electric generators.

In addition, the 2011 and 2013 capital cost may not have been expressed in the same terms. See below.

i. The 2011 RPP used an assumed capital cost per kw of capacity of $1,239 in 2011 dollars (Table No. 12, p. 96). The range of capital costs was given as $1,073 to $1,386 per kw in 2011 dollars.

ii. The 2013 RPP used an assumed a capital cost of $1,425 in 2013 dollars (p. 30 Vol.2, Chapter 2, elevation 3,500 ft.).

iii. The CPI increased by 3.6 percent between 2011 and 2013. This suggests an increase in the capital costs per kw for a CCCT in real terms of about 10 percent between the 2011 and 2013 plans. The 2013 cost per kw, however, is within the range of values estimated in the 2011 RPP when that range is adjusted for the value of the dollar.

iv. The 2013 RPP made clear that it was providing the generation adjusted for altitude. The effective capacity of a CCCT at 3,200 feet is significantly less than the capacity at sea level or 1,500 feet. The 2011 RPP expressed the capacity of the CCCT in round numbers, e.g. 300 mw, suggesting that the cost was being provided before adjusting for loss of capacity due to altitude. That difference can be significant. The 2013 RPP listed the capital cost per kw of a CCCT at 1,500 feet as $1,332 per mw as opposed to $1,425 per mw at 3,500 feet. (Vol. 2, Chapter 2, p. 32, both 7FA.04 Air Cooled Condenser) So if the 2011 plan's *listed* capital cost per kw had not yet been adjusted for altitude, the real capital cost in 2013 may have actually been lower per kw.

c. All costs within the modeling were <u>not</u> escalated at the same rate. The cost of market electricity was escalated at 2.1 percent (the assumed rate of general inflation). The cost of capital expenditures in the hydros was escalated at 2.5 percent. There is no reason to believe that all costs should escalate at the same rate. The 5 percent escalation rate came from the particular EIA carbon cost scenario that NWE adopted. Dr. Power simply sought to carry out a sensitivity test to see how the escalation rate impacted the results. Of course there are an infinite number of escalation rates one could use.

It is interesting to note that NWE chose a relatively low escalation rate for the carbon costs. Its initial $16 per short ton (2012$s) value in 2021 put it in the "middle of the pack" compared to other utilities but because of its relatively lower escalation rate, after two decades it was at the low end of the group of utilities shown in the figures on page 10 and 11 of Dr. Power's testimony.

One of the reasons for utilities assuming a relatively high rate of escalation is that the carbon cost is assumed to be the result of federal policy that places increasingly strict limits on overall carbon emissions and the cost rises to reflect that increasing scarcity of the right to emit the carbon.

It is interesting to note that Evergreen Economics, the consultant hired by the Commission to review the NWE-Ascend modeling of the hydro purchase and alternatives, faulted NWE and Ascend for "not fully captur[ing] the range of values used in resource planning elsewhere in the industry (e.g., CO2 prices, Northwest natural gas prices)." (p. 22, Final Assessment, March 27, 2014) Evergreen Economics also noted that in modeling the uncertainty about carbon costs, the NWE "[r]ange of uncertainty falls at [the] lower end of the CO2 values used for resource planning in other Western utilities." (p. 6)

d. In its 2013 RPP NWE did point out that connecting two gas turbine-generators to one steam turbine generator improved the efficiency of a CCCT compared to the configuration NWE chose to model in which only one gas turbine-generator was attached to the steam turbine. NWE's explanation for why it chose that configuration was that it did not need an additional 600 MW (nominal) of generating capacity that a "two-on-one" configuration would produce to meet its customer's loads. (Volume 1, p. 5-27)

As this question points out, that problem of excess supply can be potentially solved by finding a partner who would take half of the output from the larger and more efficient unit.

The MDU 2013 IRP only proposes to "begin work on the potential partnership in a large combined cycle resource to be online sometime after 2020." (Vol. I, p. 51) MDU proposes to take 200 mw of a 560 mw CCCT. NWE is looking for a larger incremental source of supply at an earlier time.

As NWE points out, the citing of a CCCT has to take into account the availability of sufficient natural gas pipeline capacity to service the large gas-fired generator, the availability of transmission capacity to move the electricity to NWE's (and its potential partner's) load center, and, for maximum efficiency, the availability of large quantities of water for efficient cooling. The altitude at which the CCCT operates also determines its fuel efficiency.

If the CCCT is located at some distance outside of NWE's service territory, then the transmission losses as well as the wheeling costs or additional transmission construction costs have to be taken into account. Finally a "partnership" may impose some constraints on how flexibly NWE could use its share of the generator.

NWE service territory in Montana is relatively isolated from the load and generating centers of other regional utilities. This may increase the cost of "partnering" and reduce its benefits.

An electric resource supply decision of this sort (i.e. partnering on a larger generator potentially located outside of NWE's service territory) is a practical engineering economic decision. It is not clear that a decision between opting for a smaller solely-owned CCCT as oppose to arranging for ownership of a share of a larger unit can be simply labeled "proper" or "improper." While NWE may not be obligated to explicitly consider the latter option in its resource procurement process, neither would it be inappropriate to do so.

PSC-257

Regarding: Using Market to Meet Customer Needs
Witness: Power

You write "Adding no additional generating resources to NorthWestern's current portfolio would require NorthWestern to go into the regional electric market for about half of the electric energy needed to serve customers' loads…That would expose customers to potentially volatile market electric rates for almost half of all the electricity that NorthWestern provides to its customers." (20:17-21)

a. These sentences describe the status quo, and the situation as it has been over the past several years, do they not?

b. Are long-term power purchase agreements volatile?

c. Has the seven-year contract under which NorthWestern is currently taking power from PPLM proved volatile?

d. Do you agree with Ascend that price spikes are typically followed by a reversion to a mean in market prices for electricity and natural gas?

e. In most other situations, even for necessary commodities like gasoline, consumers have to pay the prices the market delivers, volatile though they may be. Why would it be catastrophic to have electric consumers do the same for half of their supply, given that they are generally subject to price volatility for all commodities, all the time?

Response:

a. Yes.

b. "Long-term" typically means more than one year. In that setting, yes, they can be volatile. Even the five-year contracts with PPLM have led to concerns about the "cliff" at the end of the five years and the necessity to find alternatives.

   Of course, if "long-term" meant what it means in common language, then, by definition, long-term agreements "lock in" fixed prices and there is no volatility. But that is not what the words "long-term" mean in this context.

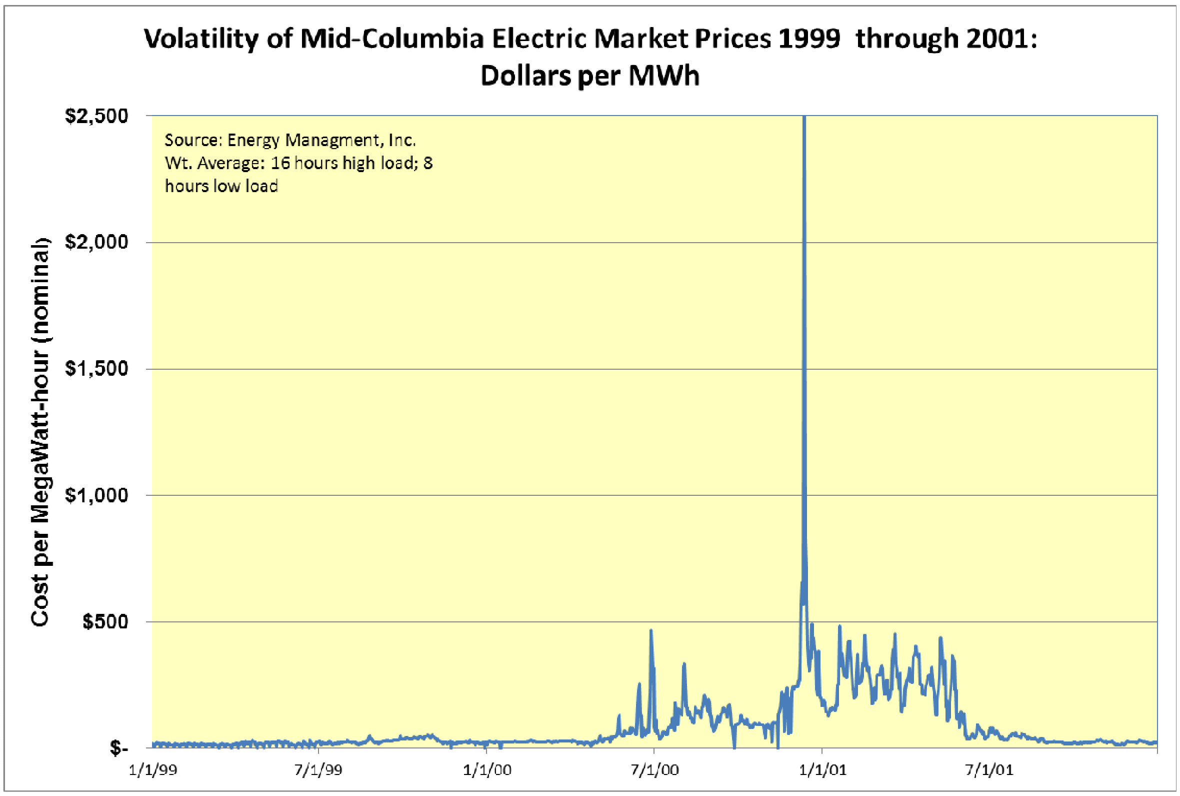
c. No. It has provided seven-years of stability. That is an improvement over five-years and an improvement over one-year plus.

d. Yes, but that is true by definition: a "spike" is a temporary increase in price followed by a decrease. Commodity prices often move in that pattern. That does not mean that no damage is done during the spike. As John Maynard Keynes said: "But this *long run* is a misleading guide to current affairs. *In the long run* we are all dead. Economists set themselves too easy, too useless a task if in tempestuous seasons they can only tell us that when the storm is long past the ocean is flat again." (*A Tract on Monetary Reform*, Chapter 3, 1923)

e. The Montana Legislature appears to have been concerned about the risk associated with electric supply. It specified one of the duties of a public utility as: "identify and cost-effectively manage and mitigate risks related to its obligation to provide electricity supply service." (MCA69-8-419(2)(c))

   Most people are hurt by instability and volatility in the economy. That instability or volatility is not something anyone but speculators and hedge fund managers welcome.

The economic “spikes” or booms and busts can wreak havoc on the economy. Part a. of this data request curiously mentions “the status quo” which is defined as the “last several years.” Consider, however, the disabling volatility of the regional electric market in the 2000-2001 period when electric prices rose to as high as $2,500 per mwh on a daily average basis and for almost a year market electric prices regularly approached $500 per mwh. See the figure below. These prices led to most industrial operations in Montana shutting down (lumber mills, paper mill, oil refineries, mining, etc.) because of the high electric prices. In addition, the price increases swamped the price volatility of “commodities” of the sort referenced by the question.



At the national level the initial spikes in energy prices in the 1970s and early 1980 did serious damage to the national economy. More recently the “bubbles” in various sectors of the economy with prices rising steeply and then tumbling down also disrupted the economy. The inflation of the housing bubble and then its bursting led to the Great Recession from which we have only barely recovered.

PSC-258

Regarding: Best Practices for Resource Planning

Witness: Power

a. Are you aware of any other examples of utilities who undertake the completion of a resource plan only after agreeing to purchase a very large resource?

b. Should the Commission be concerned that the typical purpose of a resource plan—to surface the best resources to acquire, before their acquisition—is seemingly not the purpose of the 2013 Resource Procurement Plan?

c. If the answer to sub-part (b) is yes, how should the Commission regard the reliability of evidence presented in the 2013 RPP?

Response:

a. No.

b. Resource plans rarely deal with "real" resources. They focus on generic resources and involve no utility-specific nor site-specific details. Including a "real" resource with all of its specific details would appear to make the planning analysis more useful and relevant. It is likely that if NWE had not availeditself of the opportunity to purchase the hydro assets, the 2013 Resource Procurement Plan would have served a more traditional planning function.

c. The Commission should find the information in NWE's 2013 Plan useful since it goes beyond the analysis of hypothetical resources that typically are analyzed in utility IRPs. The Commission can and should judge for itself the reliability of the 2013 Plan. However, it should be noted that the Commission has had the benefit of Evergreen Consulting's analysis. In addition, as this question indicates, the 2013 Plan is being used to support the hydro acquisition; accordingly, it is subject to testing during a contested case. Thus, the review and consideration of the 2013 Plan exceeds what normally occurs.

The schedule under which NWE was required to carrying out the Electric Resource Procurement process had required such a plan in 2012, it probably would have included something like the 2013 RPP as supplemented with the additional portfolios but without the hydro purchase alternative. None of the resources included would have been actual resources designed for NWE. Then in 2013, with the development of the hydro purchase opportunity and the application to the Commission for "pre-approval" of the purchase, it would have produced something like what was presented as the 2013 RPP with the hydro purchase included. The analysis of the alternatives against the proposed hydro purchase would still provide useful information.

PSC-259

Regarding: NWE's Bid for Thermal Assets

Witness: Power

You write, "…NWE's bid for ***all*** of PPLM's generating facilities was not a serious bid, but may have been necessary to get PPLM to look seriously at its bid for the hydroelectric facilities." (35:15-17, emphasis original). Does this mean the inputs to the NorthWestern DCF and LTRR analyses presented in response to PSC-003 and PSC-066 cannot be considered NorthWestern's firm judgment about the future liabilities, operating and cap-ex costs, and values associated with a *serious* analysis of the thermal assets? Please explain.

Response:

No. NWE in its direct testimony and data request responses in this case made clear that it looked seriously at the purchase of *all* of PPLM's Montana generating resources since PPLM was initially emphatic that it wanted to sell all of its generating resource to a single party. NWE sought to determine if there was a way of making such a purchase compatible with the best interests of its customers. It ultimately concluded that it could not. See, for instance, the up-dated response) to PSC-087a by NWE witness Brian Bird dated March 3, 2014.

PSC-260

Regarding: PPLM's Thermal Facilities, Environmental Risk
Witness: Power

At 36:1-17 you describe two categories of cost risk concerns regarding PPLM's coal-fired electric generators; 1) future environmental compliance costs; and 2) market risk associated with excess generating capacity.

a. Regarding the first category, it appears that NorthWestern built expectations of future carbon costs into its valuation of the hydro facilities. In your opinion, would it be possible to build expected environmental costs into the valuation of the coal assets, and mitigate the first category of risk in that way?

b. In your opinion, is it theoretically and practically possible to find prices for the individual assets; Colstrip 1 and 2, Colstrip 3, and the Hydros; such that an otherwise unbiased observer would be indifferent to the choice of any one of them with respect to expected environmental compliance costs? If so, should the Commission discount the environmental cost concerns raised by NorthWestern? If not, why not?

c. In response to data request PSC-066, NorthWestern provided a spreadsheet that estimates the net present value of Colstrip 1 and 2 to be minus $127 million, and the net present value of Colstrip 3 to be plus $100 million. In your opinion, do these figures represent reasonable estimates of the value of these resources?

d. In your opinion, is a detailed valuation of the proffered coal-fired resources relevant to this proceeding? Please explain your reasoning.

Response:

a. Yes. Dr. Power's understanding is that NWE *did* "build expected environmental costs into the valuation of the coal assets." Based on that understanding, Dr. Power believes that was why NWE put a negative value on Colstrip 1 and 2 which lowered the overall value of PPLM's thermal-electric resources.

b. Yes. Dr. Power's understanding is that NWE did exactly that. At least in theory, if PPLM was willing to pay someone enough money to take over responsibility for Colstrip 1 and 2, someone would have stepped forward. Since dismantling and reclaiming abandoned electric utility sites is not part of NWE's business plan, it probably would not have taken on that responsibility at any price.

c. Dr. Power has not analyzed the details of these NWE calculations and cannot offer an expert opinion on the reasonableness of those estimates.

d. It is unclear what a "detailed valuation of the proffered coal-fired resources" would involve. NWE, after studying the costs and benefits associated with PPLM's coal-fired resources concluded that those resources would not be prudent additions to the portfolio of electric resources that served its customers. Its judgment was that the purchase of the hydro resources would be a prudent and valuable addition to its electric supply portfolio. In NWE's testimony and response to data requests, NWE has explained the analysis and considerations that led it to those conclusions.

   Dr. Power is aware that there is a dispute and uncertainty regarding whether and how the PPLM thermal assets should be considered in this docket. It is also Dr. Power's understands that this is principally a legal issue, rendering Dr. Power unable to render an expert opinion on it.

PSC-261
Regarding: Hydroelectric Environmental Compliance Risks
Witness: Power

a. In your recollection, were the Libby and Dworshak dam projects unopposed on environmental grounds, or did they face significant opposition due to anticipated impacts on wildlife habitats, ecosystems, and other environmental structures?

b. Are environmental advocates now comfortable with large water projects and their effect on natural systems? Are these projects considered environmentally benign?

c. Elsewhere in the Northwest, there have been movements to remove dam structures and thus return a river to its natural or wild state. Do you believe that such a prospect is unrealistic in Montana with respect to these Hydros?

d. Assuming NorthWestern acquires PPLM's hydroelectric facilities, do you believe it appropriate to consider a measure of risk that it may incur significant unexpected environmental compliance costs, including dam removal and remediation?

e. How long do you believe the dams will remain functional for the purpose of generating electricity?

Response:

a. As Dr. Power understands it, the Libby Dam was authorized by Congress in 1951 and construction began in 1966. Dr. Power did not move to Montana until 1968. Dr. Power has no knowledge or experience with any debate over that dam.

   Construction of the Dworshak Dam began in 1966. This too was before Dr. Power moved to Montana. He has no knowledge or experience with any debate over that dam.

b. One can look at the proceedings that accompany the relicensing of each FERC regulated hydroelectric project to see what environmental issues are raised, what resolution of those issues was proposed, and what FERC actually decided. Alternatively, one can look at public efforts to actually remove existing dams to get a feeling for what percentage of existing hydroelectric facilities are proposed for abandonment and removal. Dr. Power's understanding is that despite some very high profile efforts to remove dams, for instance, some of the dams on the Snake River or on the Colorado River, those are the exception, not the rule. Both Kerr Dam and the Missouri-Madison set of hydroelectric projects went through relicensing in recent years. The controversy at Kerr was not over whether the dam should be removed but whether it should be operated with a more "natural" hydrograph. With the Missouri-Madison set of dams, there was concern that the dams on the Madison River were raising the temperature of the water and contributing to summer fish losses. That was largely a scientific debate. Although it is undisputed--and obvious—that dams change rive systems and result in significant environmental impacts, Dr. Power is aware of no wide-spread push in the United States to abandon and remove most hydroelectric facilities on environmental grounds.

c. It is Dr. Power's understanding that most of the impetus for dam removal in the Northwest is an effort to restore runs of salmon and associated salmon habitat. Dr.

Power is not aware that this is an issue at the PPLM dams that are the subject of this docket. See the response to b. above.

d. Most of the hydros have already been through environmental review by FERC and issued long-term licenses. The record of issues raised and how they were settled is publicly available. Dr. Power is not aware of anything in that record that suggests that dam removal and site remediation is a reasonable expectation either as a result of an act of Congress or a FERC order.

e. That is an engineering question that depends on the history of maintenance, repair, and replacement and the future maintenance, repair, and replacement. Dr. Power cannot offer an expert opinion on that.

PSC-262

Regarding: Facility Siting and Electricity Generation Rights
Witness: Power

a. At JMS-16:1-4 Stimatz asserts that "…ownership of the Hydros includes the right to generate electricity at those locations. These rights are extremely valuable, particularly against a backdrop of increasing environmental regulation." In your opinion, is it appropriate to assume with certainty that these rights will continue to be extremely valuable? Would it be appropriate to consider a measure of risk that their value will diminish?

b. In your opinion, did the value of Montana Power's right to generate electricity at Kerr Dam change between 1970 and 1990? Did the value of its right to generate electricity at Milltown change between 1970 and 1999?

c. In your opinion, are there important economic differences in the value of the right to generate electricity at a hydroelectric location versus the right to generate electricity at a thermal plant site such as Colstrip? Can any differences be explained using traditional measures such as the expected cost of production, transmission capacity and cost of upgrades, market access, and expected salvage and remediation costs?

Response:

a. There is risk associated with every single characteristic of any electric generator. There are an exceeding large number of such characteristics or variables. As a practical matter, only the risks that can be quantified and determined to be large and significant can be entered into the stochastic modeling. Dr. Power is not aware of evidence that the hydroelectric generating permits associated with the hydros fall into that category.

b. The right to generate electricity at the Kerr site on the Flathead Reservation was for only 50 years and had a competing applicant for the license waiting in the wings. The right to generate electricity at Milltown was probably worthless long before 1999 because of the costs associated with the facility and its massive environmental problems.

Montana Power was aware of the fact that the Confederated Salish and Kootenai Tribes, which were reluctant to have the Kerr Dam built on their Reservation, had standing to apply for the license to operate that hydroelectric facility when it came up for relicensing. In that sense Montana Power had only a 50-year right to generate at Kerr. Dr. Power is not aware of any similar threat to the hydroelectric sites associated with the hydro NWE is proposing to purchase.

The Milltown Dam generated only about 3 mw of power. However, it had accumulated almost a century of toxic sediments behind it from the copper operations in the Butte and Anaconda areas. Those toxic sediments were polluting domestic water supply for residents in the area and polluting the aquifer that is linked to Missoula's water supply. In addition FERC had classified the Milltown Dam as a "high hazard" dam. Upgrading the Milltown Dam to meet current engineering and safety standards was probably not cost-effective. As a result, NWE entered into an agreement with federal, state, tribal, and ARCO officials to remove the dam and allocate cost responsibility for that removal and remediation of the site.

Dr. Power is not aware of environmental and economic problems of a similar scale with any of the hydros that NWE proposes to purchase.

c. Dr. Power is not a lawyer and cannot speak to the legal rights that owners of hydroelectric or thermal-electric plants have to continue to generate electricity at those sites. He, therefore, cannot answer this question.

PSC-263

Regarding: PPLM's Thermal Facilities
Witness: Power

Regarding the market risk associated with excess generating capacity (36:7-17); can this risk be mitigated by reducing the probability that the total cost of producing electricity from the coal-fired assets (variable cost plus fixed cost or credit if purchase price is negative) exceeds the market price of electricity?

Response:

Yes, if PPLM would pay the new owner to take those resources and the payment more than covered the costs associated with regulation of coal-fired plants so that some of the payment could cover the market risk associated with selling the power into the market.

PSC-264

Regarding: PPLM's Thermal Facilities
Witness: Power

a. At 36:19-23 you describe NorthWestern's concern that FERC might impose additional regulation on the utility due to market power. Did FERC impose additional regulation on PPLM due to a presumption of market power?

b. Assuming that NorthWestern acquired all of PPLM's electric generators in Montana, and assuming that a significant fraction of the total capacity would be dedicated to NorthWestern's customers, is it plausible that FERC would presume that NorthWestern would have market power where PPLM did not?

Response:

a. It is Dr. Power's understanding that despite efforts to get FERC to declare that PPLM had market power and should be subject to cost of service regulation, FERC did not so rule.

b. If NWE could show that the generating resources it had were necessary to serve its existing customers and thus subject to MPSC regulation, it is unlikely that FERC would be concerned about the misuse of market power.

PSC-265

Regarding: Risk of Co-Owning Thermal Assets
Witness: Power

You write "NWE also saw the fact that it would be just one of the owners of the Colstrip facilities, having to negotiate management decisions with a group of utilities as a negative feature of purchasing just a share of Colstrip 3." (36:25-27) Where does NorthWestern record this concern?

Response:

In an up-dated response (March 3, 2014) to PSC-087a, NWE witness Brian Bird said: "Other factors that ultimately drove our $400 million bid included negative impacts on our customers due to having excess power; regulatory risks associated with FERC market power issues; <u>risks associated with not having complete control over the plants due to the Colstrip facilities having multiple owners;</u> unknown but potentially very significant environmental costs associated with complying with future environmental requirements at Colstrip; and, of course, impacts on customers' bills." (emphasis added)

PSC-266

Regarding: Risk to Montana Coal from CSAPR
Witness: Power

You testify that the EPA's Cross-State Air Pollution Rule is likely to restrict the generation of electricity with coal. (38:18-21). Does that rule affect Montana-based generators? (If necessary, please refer to the EPA's CSAPR website: http://www.epa.gov/airtransport/CSAPR/)

Response:

No. When Dr. Power referenced the CSAPR he was making a larger point about the added regulatory pressures on coal-fired electric generation

Dr. Power should have noted that EPA's Regional Haze rule requires Colstrip 3 and 4 to be making reasonable progress in reducing haze in Class I air quality areas such as National Parks.

The Regional Haze rule has gotten intertwined with the Cross-State Air Pollution Rule because EPA proposed to allow states subject to CSAPR to use the regional trading programs allowed under those regulations in place of installing Best Available Retrofit Technology (BART). Since Montana and the other Western states are not subject to CSAPR, that alternative to requiring BART to reduce Regional Haze is not relevant.

It is Dr. Power's understanding that EPA's decision on the application of the Regional Haze rule to the Colstrip generators did not require any substantial additional investment in BART until at least 2017. That decision is currently under appeal in the Ninth Circuit Court of Appeals. One of the co-owners of the Colstrip generators, Puget Sound Energy (PSE), has analyzed the potential costs it could face to upgrade the Colstrip facilities to meet expected environmental compliance requirements. PSE's mid-level estimate involves spending $190 million on Colstrip 3 and 4 upgrades by 2027. (2013 IRP, Appendix J, page J-18) The Washington Utilities and Transportation Commission has asked Puget Sound Energy to analyze those costs again to demonstrate that continued investment in the Colstrip generators is justified and that the Colstrip generators are financially viable. (WUTC press release, February 6, 2014, Docket Numbers: UE-120767 and UG-120768)

PSC-267

Regarding: EIA Projections Concerning Coal
Witness: Power

You include an EIA forecast of expected generation from various resource types on page 41 of your testimony. You write, explaining the chart, "Actually, despite the fact that it seems likely that no or almost no new coal-fired electric generators will be built, the amount of electricity from coal-fired generation will increase modestly between 2012 and 2030 as the existing coal-fired generators are utilized to a greater extent." (41:7-10).

a. Do you expect that this statement applies to what one reasonably could expect to see from Colstrip Units 1, 2, 3 and 4? Explain.

b. You state that Powder River Basin coal "will continue to play an important role in the nation's and Montana's energy portfolio for several decades into the future." (44:8-10). Are you concluding that Colstrip and other Powder River Basin coal burners will thrive even if carbon is regulated?

c. Do you expect that the Commission's decision in this docket would have impact on the viability of the Colstrip assets?

d. Do the EIA projections you depict on page 41 assume a carbon price that influences the electric generating mix of the U.S. electricity supply?

Response:

a. It is problematic to suggest that nationwide projections of the sort made by EIA apply to specific facilities. But, generally speaking, if all four Colstrip plants continue operating, yes. As projected natural gas and market electric prices rise, coal-fired plants are likely to be operated more hours of the year and idled for economic reasons less often.

b. No. Operators of Powder River Basin coal mines and of regional coal-fired generators burning that coal probably would probably not describe their current economic situation as "thriving." The decline in natural gas costs, the reduction in demand for coal and electricity due to the Great Recession and the slow recovery from it, and the accumulating impacts associated with the regulation of the emissions associated with coal-fired electric generators have created a challenging situation for coal-miners and owners of coal-fired generators.

   However, for the foreseeable future significant amounts of coal will continue to be used to generate electricity. The impact of carbon emission regulation will, as intended, systematically raise the cost of using carbon intensive energy sources. That will lead to adjustments in technology as well as energy usage patterns. The response will be entrepreneurial and will not involve the coal industry simply giving up and vanishing. See the response to PSC-247(c).

c. No.

d. The AEO 2014 Reference Case does not assume that a carbon tax is imposed. If it follows the AEO 2013 Reference case, it does assume that the risk of increasingly strict emissions regulations on coal-fired generators will lead investors in carbon intensive generation to demand a higher cost of capital and that will contribute to a shift away from coal-fired generation towards less carbon intensive fuels.

The AEO 2014 scenarios including the GHG15 scenario had not been released by April 25, 2014. The AEO 2013 GHG15 scenario which had the carbon cost being realized this year (2014) showed a major impact on the use of Powder River Basin coal and coal in general over the next 30 years. For Montana PRB coal the projected production in 2040 was about the same as the production in 2012, about 6 percent lower. Wyoming PRB coal production was projected to fall to over 60 percent below the 2012 level. However, without the $15 carbon costs escalating at 5 percent, the AEO 2013 Reference case had Montana coal production more than doubling. So relative to what EIA projected would have happened to Montana coal production, the $15 carbon cut Montana coal production in more than half.

PSC-268

Regarding: Commission Precedent on Paying Avoided Carbon Price to Generators
Witness: Power

Independent generators who take avoided-cost rates established by the Commission are not paid today for the future value of the carbon emissions they avoid. NorthWestern has argued against paying them for avoided carbon. (Wilson 18:15-19:12). The Commission has, in that instance, agreed with NorthWestern. Why should NorthWestern be treated differently than these generators?

Response:

For independent generators who sign contracts for the output of the generators over the expected economic life of those facilities, the same approach to avoided cost should be used, adjusted for the term of the contract, as is being proposed by NWE in this docket. The MPSC does periodically modify its method of calculating avoided costs for resources obtained under different contract terms and in different economic and market conditions.